ALBERTA CHAMBER OF RESOURCES

ALTERNATIVES FOR PROCESSING CANADIAN HEAVY OIL

Prepared by:
ACR Oil Sands Task Force

December 1987

ALBERTA CHAMBER OF RESOURCES

January 4, 1988

The Honorable Neil Webber
Minister of Energy
Government of Alberta
EDMONTON, Alberta

Dear Dr. Webber:

On behalf of the ACR Oil Sands Task Force, I am pleased to present to you three (3) copies of a short report titled "Alternatives for Processing Canadian Heavy Oil and Bitumen".

This report complements the Task Force's more recent study on the Regional Upgrader and Satellite Production Facilities Concept which was presented to you last month. Although, this current report is preliminary and does not contain any quantitative information, it points out potential benefits of various processing alternatives. Among the cases considered, the option of "Upgrading Capacity Additions" to the existing integrated oil sands plants is projected to offer the greatest synergisms with potential savings in capital and operating costs.

As it was indicated to you in my letter of December 11, 1987, the Task Force's efforts will be continuing during 1988, and therefore your views on the subject and feed-back from Alberta Energy will provide the Task Force with the necessary input for its agenda.

On this occasion, I would like to express my appreciation to you and to your staff for your continuing interest in the Task Force's programs, which combine the efforts of a large membership from industry and government organizations with a particular support from AOSTRA.

Yours truly,

Erdal YILDIRIM, D.Eng.Sc.
Chairman
The ACR Oil Sands Task Force

EY/lw
Attachments

cc: Mr. D.V. Currie - ACR Managing Director
Oil Sands Task Force Members

ALTERNATIVES

FOR

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PREPARED BY:
THE ACR OIL SANDS TASK FORCE

DECEMBER 1987

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ABSTRACT

The ACR Oil Sands Task Force has proposed the concept of a regional upgrader as a means of promoting oil sands development. In this concept, heavy hydrocarbons produced from production sites would be transported for upgrading at one regional plant. To date, small scale production of bitumen has been sold without upgrading; but, the time is rapidly coming when the bitumen market will be saturated and the production of Alberta's heavy hydrocarbcns will be constrained by the lack of upgrading facilities. The Task Force has been publicizing the concept and emphasizing the need for upgrading capacity in the region to avoid this constraint. The concept could provide an upgrading service for a number of these small producers. The studies to date have produced competitive "social supply costs" for bitumen produced by the satellite production facilities and processed at a regional upgrader.

There are other alternatives, however, to a grass roots upgrader for processing Alberta's heavy hydrocarbons. This paper reviews these options including upgrading capacity additions to the existing oil sands plants and refineries. The review points out the synergism that may exist in establishing additional capacities at these plants. Further, it shows that the option of partial upgrading in various producing fields and then hydrotreating at a central plant is encouraging. However, the determination of true economics for these alternatives require site specific evaluations.

ALTERNATIVES
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1.0 INTRODUCTION

The ACR Oil Sands Task Force proposed the concept of a regional upgrader and the satellite bitumen/heavy oil production facilities in a position paper which was published in 1986 (1). The position paper also outlined an action plan for carrying out the necessary screening studies to verify the advantages of the concept postulated by the Task Force.

Earlier this year, the Task Force completed a preliminary study for determining the representative costs for oil sands projects (2). The study was based on the more current performances of the existing oil sands plants as well as the recent project evaluations conducted by the member organizations. The representative costs study showed that a) the synthetic crude oil (SCO) from oil sands could be produced at C$30 - 32 per barrel and b) based on the social supply cost of SCO, the Regional Upgrader and the Satellite Production Facilities Concept would be competitive with the integrated mega project approach. It would also offer a more affordable development opportunity.

Throughout the year, the Task Force has made public presentations and met with the representatives of the Alberta and federal governments to emphasize the need for bitumen/heavy oil upgrading capacity and publicize the advantages of the proposed concept. The Task Force continued publishing new position papers (3), (4) and (5) while undertaking a more detailed study for evaluating

the economic viability of the concept. The results of this study (6) has recently been presented to the representatives of the Alberta Energy Department.

Although the advantages of the proposed regional upgrader and the satellite production facilities have been confirmed by the recent evaluation, the Task Force has also been aware that there are other alternatives for processing Alberta's heavy oil and bitumen other than a grass roots plant. Recognizing that some of these alternatives may be less capital intensive, the Task Force requested from some of its members as well as from outside consultants preliminary studies and notes. This paper is an attempt to summarize these input of various sources.

2.0 DEVELOPMENT AND PROCESSING OF ALBERTA'S HEAVY HYDROCARBONS

The National Energy Board (NEB), in their October 1986 Canadian energy supply and demand summary, stated that the productive capacity from reserves additions of conventional light crude would be insufficient to replace productions in the interval until 2005. The prospects for maintaining Canada's status as a net oil exporter strongly depend on the country's ability to develop Alberta's oil sands and heavy oil resources.

2.1 RATIONALE FOR DEVELOPING ALBERTA'S RESOURCES

Similar to the NEB projections, the ERCB also forecasts a decline in conventional reserves as production exceeds new discoveries. This trend is expected to continue as the Western Sedimentary Basin matures as an area for conventional oil exploration and production, with fewer and smaller prospects remaining to be discovered.

In contrast, less than 0.5 percent of the remaining bitumen and coal reserves were produced in 1986. Taken together, the supply from these two sources constituted 20 percent of Alberta's total energy production and these sources represent 87 percent of the remaining reserves.

Of all the energy produced in Canada, fully two-thirds come from Alberta. Canada's reliance on Alberta's energy is even more striking if one takes into account only the conventional crude oil, natural gas, and synthetic crude oil produced in Canada. Of these resources, Alberta produces 88 percent of the Canadian total.

Reserves also are an important indicator of future trends. In 1986, Alberta's total reserves of crude oil, natural gas and bitumen accounted for 91 percent of Canada's total reserves in these three categories as shown below.

Remaining reserves at the end of 1986 (in Petajoules)

	Alberta	Canada	Alberta's Percentage
Conventional Oil and Equivalent	24,940	33,300	75
Natural Gas and Equivalent	71,060	86,360	86
Bitumen	154,000	154,000	100
TOTAL	250,000	273,660	91

Based on the magnitude of these reserves, one could conclude that the prospects for maintaining Canada's status as a net oil exporter are contingent on the development of Alberta's undeveloped reserves.

2.2 RATIONALE FOR UPGRADING IN ALBERTA

The construction of a regional upgrader or establishment of a similar upgrading capability in Alberta would provide an alternate market for bitumen and heavy oil. Currently, heavy oil producers supply asphalt plants and a limited number of refineries in the U.S. and Canada that can accept heavy feedstock. This market, however, has the following shortcomings:

- The market is finite. Alberta has the potential to produce much more bitumen and heavy oil than this market can absorb.

- For pipeline transportation of heavy crude oil to the market, this feedstock must be mixed with a diluent. Requirements vary from 15 percent for lighter heavy oils to 45 percent for Athabasca bitumen. This diluent is normally condensate from natural gas, a commodity that is forecast to be short supply in the near future. Diluent also reduces the effective pipeline capacity. As lead is phased out from gasoline and octane becomes an increasing concern, diluent becomes less and less attractive as a refinery feedstock.

- By exporting heavy oil or bitumen, Canada loses both the added value and technologies that go with upgrading to synthetic crude oil. It also exports potential jobs.

In addition to requiring about 45 percent diluent in the blend to meet pipeline specifications on viscosity, Athabasca bitumen normally contains 3 to 5 percent water. This imposes an economic penalty through down grading of the diluent that almost precludes Athabasca bitumen from the export markets. The alternative of upgrading at the point of production or at a different location such as Edmonton, obviously overcomes this problem.

A regional upgrader or a similar upgrading facility would produce synthetic crude oil which is acceptable to varying degrees, as feedstock to most refineries. There are no concerns with respect to diluent or pipeline capacity, jobs are created, expertise in technology is developed and retained in Canada.

2.3 PROCESSING ALTERNATIVES

Currently, two oil sands operations which produce bitumen through surface mining and extraction steps, also process the produced bitumen to a high quality synthetic crude oil at the points of production. These operations are known as the integrated oil sands plants which are fully equipped with upgrading process units and do not depend on external facilities for upgrading. There are no upgraders at the sites of in situ operations which produce bitumen or heavy crude oil. However, the integrated plant configuration is also possible in conjunction with the in-situ applications.

Generally, the integrated oil sands projects are mega projects in sizes over 50 Kbls/CD and require large sums of initial capital investment. In addition, the projects combine complex processes of mining, extraction, upgrading and utilities. This, in turn, necessitates large and complex organizations combining variety of

skills and different cultures. The overall plant reliability is highly dependent on the reliability of individual plants and process units. Disruptions in any part of the plant may influence the performance of the total plant. If major disruptions occur in the down stream process units, the plant's bitumen production capabilities may be idled.

Strength and weakness of the integrated plant configuration are fairly well known by the industry. Oil sands and heavy oil development through the integrated plant projects is still a viable option. Implementation of this option, however, does require high front-end capital and does not necessarily allow multi-lease development unless the upgrader module of an integrated plant is constructed with excess capacity to accept off-lease produced bitumen.

There are other alternatives to the integrated plant configuration that would be very beneficial to the industry. However, analyses by various organizations indicate that it is virtually impossible to generalize on the merits and demerits of these schemes without specific development scenarios. These various approaches are given below:

1. Regional or Central Upgraders;

2. Upgrading Capacity Additions to the Integrated Plants;

3. Upgrader Integration with Refineries;

4. Partial Upgrading by Field Upgraders and Centralized Hydrotreating.

Following sections will present our general views based on very preliminary studies.

2.3.1 REGIONAL OR CENTRAL UPGRADERS

This particular configuration has been proposed by the ACR Oil Sands Task Force including a number of satellite producers to supply bitumen or heavy crude to the Upgrader. The advantages and issues associated with this approach have been publicized in a number of position papers published by the Task Force and given in the reference list (1), (2), (3), and (4). A more recent report (6) representing the results of a detailed preliminary evaluation of this concept will be ready for distribution very soon.

2.3.2 UPGRADING CAPACITY ADDITIONS TO THE INTEGRATED PLANTS

In Alberta, there are two integrated oil sands plants operated by Suncor Inc. and Syncrude Canada Ltd. These operations actually combine four industries into one: a single major plant complex consisting of large mining operations, interdependent and interrelated with extraction, utilities and upgrading. The upgrading complex at both plants consists of primary and secondary upgrading units. Both plants utilize some form of coking technology in primary upgrading which is based on the principle of "carbon rejection". The existence of the cokers at the both sites offers a major advantage for capacity additions utilizing more current upgrading technologies based on the principle of "hydrogen addition". For example, Syncrude Canada Ltd. is in the process of increasing its upgrading capacity by about 20 KBbls/CD by installing a "hydrogen addition unit" also called "hydroprocessor" and other process units. In this case, the incremental upgrading capacity will be met from Syncrude's own bitumen production. Similarly, Suncor Inc. has recently announced a debottlenecking project to increase the integrated

capacity for its Ft. McMurray plant to 63 KBbl/CD and to provide a further 10 KBbls/CD of upgrading capacity for off-lease produced bitumen.

Suncor's announcement to provide an upgrading capacity for off-lease bitumen supports the Task Force's view that the integrated plants are viable options for upgrading capacity additions in larger dimensions. This option presents significant advantages and some likely disadvantages.

Further capacity addition would most optimally be developed by installing "hydrogen addition" process units prior to the existing cokers. While this approach is expensive, it has many pluses:

- High incremental yield in the range of 105% - 110% of bitumen feed.
- Identical or reduced SO_2 emissions.
- Better quality intermediates, probably leading to a better overall SCO quality.
- Improved reliability for the overall complex due to added parallel or "parallel in emergency" unit configuration.
- More reliable hydrogen production and sulfur recovery due to added parallel units.
- The more the number of intermediate hydrotreaters, the better in optimizing the product quality.

- o Better use of support facilities and existing technical personnel.

It should be stated that capacity addition could only be considered in conjunction with plot space availability and process fitness.

There are also some concerns associated with this approach, for example, higher ash in coker feed and more sensitivity to variances in bitumen quality. There will be virtually no possibility of selling coke which Suncor Inc. has done from time to time.

Existing pipelines may not take added SCO without major changes. Also, added gas will be needed - much more per barrel of feed than with existing facilities. Synthetic gas liquids (SGL) will be reduced in yield and will be lower in olefins reducing sales value.

Significant amounts of electricity will be needed incrementally - risk buying from the grid for units with high risk on loss of H_2 circulation? Incremental heat for extraction will not be major - only from new hydrogen generation facilities.

As in any similar setting, the upgrader will protect its own feed in case of upsets or crises - external feeds will be dropped first.

Philosophy differences between external supplier and upgrader and upgrader owners are inevitable. Getting agreements will be very difficult. The time to build new facilities will be extended and costly due to difficulties in working in an existing plant - the

safety concerns of the existing operator will be very real but difficult to convey to outsiders, including external feedstock producers.

The incremental SCO product may not be of high interest to potential buyers who are not directly related to the incremental feed supplier. Unlike most existing owners who have their own SCO outlets, the marginal feed supplier probably will have to sell his SCO on the open market; and the market for current SCO is thin beyond existing users.

2.3.3 UPGRADER INTEGRATION WITH REFINERIES

This section addresses the relative merits of constructing a bitumen upgrader which is integrated into an existing refinery, compared to a standalone plant.

The format used here consists of a listing of issues, with a short commentary on each point. The list is broken down under the headings 'technical' and 'non-technical'.

2.3.3.1 STUDY BASIS

The following assumptions are implicit in this review:

- An integrated upgrader adds significant new capacity to the base refinery throughout, of at least 30KBbls/CD of bitumen feed.

- There is only limited 'spare' processing capacity in place for the cracked oil streams from a primary upgrading unit. That is, limited hydroprocessing and sulphur clean-up; new plant analogous to the standalone plant equipment would be needed.

- o Base refinery feedstock throughout will not be significantly displaced, and the refinery continues to fulfill its normal processing commitments.

- o The integrated upgrader is a facility available to various bitumen producers, to convert their material to light synthetic crude, of similar quality to existing SCO production from oilsands.

2.3.3.2 TECHNICAL ISSUES

1. Potential for Capital Cost Savings, Through Maximum Use of Existing Capacity, & Infrastructure

   - o Primary upgrader will cost the same, but may use fractionator.

   - o Secondary upgrading (hydrotreating and hydrogen plant) may be partially done in existing plant, modified to enhance/expand capacity/performance. However, the cracked products are much tougher to treat than virgin stocks, and extensive new hydrotreating equipment will be needed.

   - o Services, (i.e. steam, air, water, power, piperacks, waste handling), can be incrementally expanded as required, with some savings compared to grassroots costs. May be useable spare capacity already in place. Some processes create surplus energy, actually reducing steam generation needs for refinery.

- Power requirements, particularly for high pressure processes, are high. Will need incremental supplies, of similar cost to standalone case.

- Bottom of the barrel disposal (pitches) would be needed, but an existing coker may handle this problem. The coker would be the key bottleneck in the new configuration, unless existing crudes are backed out.

- Offsite systems (tankage, pipelines, waste treatment) present opportunities for extensive use of existing facilities, with some capacity increases. Still need new feedstock tankage, and diluent return system, as for standalone.

- Savings on site access, preparation, civil works, major site services which are already in place. However, space is usually at a premium in a refinery, so site costs may still be high.

- Existing maintenance facilities, fixed and mobile, can be extensively used for the expanded plant, with some additions, such as spares holding and warehousing, workshop expansion.

- Sulphur recovery systems will have to be expanded by several times, with some savings through expansion of existing plant.

2. Potential for Indirect Capital Cost Savings

- o Use of refinery project and engineering staff to the extent possible, will provide some engineering cost savings and preproduction and startup cost savings through use of a "refinery startup team" borrowed from base plant personnel.

- o All construction support and management needs are as for standalone, including construction camp, warehousing, site facilities, which would be kept separate from base refinery.

3. Environmental Issues

- o Depending on the technology chosen for upgrader, there will be new solid, liquid, and/or gaseous waste streams to deal with. Where residue waste stockpiling may be acceptable at a remote standalone site, space constraints will almost certainly preclude this at a refinery. This means further expensive treatment, such as gasification; or if a coker is available for pitch disposal, there is the possibility of making saleable coke.

- o A primary upgrading process which gasifies the bottom of the barrel would probably be attractive, with the potential for heat integration into the base operation. This in turn could lead to reduced steam plant costs, and also power generation may be attractive using the surplus energy, (up to total site needs at least).

4. Manpower

- o Integration of the utility, offsites, and general services areas, as well as control rooms, will mean only small incremental manpower, and hence considerable operating savings.

- o The new process area will need a full new complement of operators, as for standalone.

- o Management, engineering and support personnel would need only incremental increases, with redefinition of duties.

- o Similarly, maintenance manpower, while needing increase, will in total be less than for the standalone case.

- o From the other perspective, however, substantially fewer permanent jobs will be created than for standalone - possibly 10% to 15% less overall.

5. Base Plant Operations Integrity

- o Variability of the new feeds to the upgrader, (several sources), for both quality and quantity, will impact the operation of the downstream process equipment. Where integrated, this always is detrimental to those, base refinery, operations.

- o Great care must be taken when integrating the utilities systems, in which the new plant portion

may be a significant surplus energy producer, or energy consumer. Upset to the upgrader could severely impact base operations. Such effects can be mitigated, but at the expense of building standby systems as backup, with complex control.

- o The need for many tie-ins to the existing equipment will interrupt base operations. Scheduling of these is critical.

- o A major difficulty is restart of an upgrader in winter, after an unplanned outage. The existence of a running base operation can avoid the "black-start syndrome". This is a significant design issue.

6. Site Suitability

- o New plant, particularly the offsite equipment such as feed storage, needs considerable space. This is generally at a premium in a refinery, and is likely to define a capacity limit for the upgrader.

- o This also constrains, if not precludes, the possibility of phased expansion to meet further Provincial demand.

- o Excessive equipment congestion can impact insurability both of the old and new plant.

2.3.3.3 NON TECHNICAL ISSUES

1. The Owner of an Existing Refinery May Not Welcome 'Other' Ownership on Site

   o Given that the upgrader is aimed at providing a service to producers, the new plant is likely to involve a joint venture, as for a standalone plant. The presence of JV owners on-site adversely impacts the refinery operator's autonomy and creates real management headaches.

2. The Existence of a Skilled and Stable Workforce

   o This means that the full range of processes, regardless of complexity, can be considered. Whereas, for a grassroots and/or remote plant, technical and operability risk considerations tend to direct the process configuration towards simplicity, hence narrowing the choice.

   o It also means that a faster throughput buildup profile (probably under 2 years), and generally more stable and efficient operations, can be hoped for.

   o Training of new operators is facilitated.

3. The Refinery Owner as Bitumen Producer

   o There will be an inclination to preferentially use the upgrader for own corporation's production

processing, in case of integrated oil companies. This consideration alone could preclude the Regional Concept at a refinery site.

4. Base Refinery Feedstock Processing Obligations

- o Should the close integration of the upgrader mean that existing feeds are backed out, then the supplier of these crudes has to find alternative (export) markets with associated extra transport cost, thus reducing his netback.

- o Such feed substitution may also be unacceptable to the refinery owner, as a policy.

5. Operating Permits

- o Fresh scrutiny of existing permitted emissions is likely, and could lead to imposition of reductions through use of new available technologies. This would be unpopular.

6. Access to Process Capacity by Producers

- o Assuming that producers, or joint venture participants, have some guaranteed access to upgrader capacity, then penalties would apply should the base refinery operation cause outage of the integrated upgrader.

- o A considerable accounting and planning effort is involved in administering and controlling a

processing service which is closely integrated with an "independent" refinery operation which shares facilities.

- o These considerations point to the significant advantage of limiting the physical degree of integration of the upgrading and base operations. The tradeoff is, of course loss of capital cost savings for this concept.

2.3.4 PARTIAL UPGRADING BY FIELD UPGRADERS AND CENTRALIZED HYDROTREATING

Bitumen and very heavy crudes normally require heat for production in the form of steam; and a diluent for pipeline transportation, in the form of condensate from natural gas. In view of these requirements for production and transportation, the option of "partial upgrading" at the satellite facilities in the field plus "hydrotreating" at a central facility look attractive. As coke or equivalent product must be rejected even in hydrogen addition processes, this "bottom of the barrel" product could be used as energy source in the field for steam generation. Thus, through partial upgrading, the production and transportation requirements could be fulfilled: partial upgrading would reduce viscosity and provide low cost energy for steam generation.

The process to be chosen for partial upgrading should have the following attributes:

- o It should be simple and have good operability characteristics for use in a remote location and difficult environment.

- o It should give a high yield of liquids, ideally leave no residual such as pitch or coke.

- o The ability to be extensively modularized, (i.e. built as far as possible in a fab-shop at a major centre), and transported to the site for minimal field erection.

- o Capital cost and operating cost should be low, as these costs are to be set against the current costs of dilution.

The ACR Oil Sands Task Force is aware of the existence of two or three processes that mostly satisfy the above criteria. Some of these processes are commercially proven in some other countries on other feed stocks. However, there is no commercial application in Alberta that utilizes any one of these technologies. Therefore, a large scale process demonstration by using Alberta heavy crude and bitumen would be essential prior to commercial applications in Alberta.

The partially upgraded crude from any primary upgrading process still requires further hydroprocessing, to reduce contaminants (nitrogen, sulphur, certain unsaturated hydrocarbons), before a "finished" synthetic crude is achieved. This could be performed at several existing refineries, but the volume is very limited without addition of new equipment. This also depends on the primary technology chosen.

This raises the prospect of a "Central Hydrotreating Facility", analagous to the Regional Upgrader concept, which could gather partially upgraded crudes from various in-situ production sites. Each upgrader at the wellhead area would, in turn, have gathered crude from several wells. A plant capacity of 5 KBbls/CD is

probably the smallest economic size for these units. There is no particular upper limit, but modularization savings will rapidly reduce above the 20 KBbls/CD, dependent on the technology being considered.

The main advantages of this concept are:

- o The elimination of use of duluent for transport by pipeline.
- o The costs of primary upgrading are spread between multiple relatively small-scale plants, which are closely integrated with the production facilities and steam systems.
- o The product will be worth at least as much to a refiner as bitumen blend.
- o The capital cost of the central hydrotreating facility will be substantially reduced, through the absence of a primary upgrader.
- o If the process produces recoverable heat, then there is a credit for useful steam production which is reinjected to the well.
- o If blended with bitumen, it can be used as a diluent itself, assuming the upgrader produces a crude product below pipeline viscosity specs.
- o The concept can be complementary to a full Regional Upgrader, if spare hydrotreating capacity is built in for the partially upgraded crude.

3.0 SUMMARY AND CONCLUSIONS

The province of Alberta possesses immense resources of very heavy crude and bitumen and Canada's status as a net oil exporter of energy strongly depends upon the development of these resources. However, a sustained development program for heavy crude and bitumen is contingent upon the availability of upgrading capacities in Alberta.

There are a few alternate ways for processing Alberta's hydrocarbons. One well recognized approach i.e., integrated processing together with bitumen production facilities has been implemented at two commercial oil sands plants. The other approaches include: 1) Regional or Centralized Upgraders, 2) Upgrading Capacity Additions to the Integrated Plants, 3) Upgrader Integrations with Refineries, and 4) Partial Upgrading by Field Upgraders and Centralized hydrotreating.

The first three alternatives are technically feasible. The capacity addition alternative at the existing oil sands plants seems to offer the greatest synergism which may translate into significant capital and operating cost savings. All three alternatives however, will require high level cooperation, coordination and mutual agreements between the bitumen producers and processors.

The option of partial upgrading and central hydrotreating offers attractive features. This, too, will require cooperation and coordination between the producers and processors. Furthermore, the application of this concept is contingent upon successful completion of large scale process demonstration tests.

Finally, it should be pointed out that some of the alternatives reviewed in this paper involve the existing refineries and oil sands plants. Technical and economic merits of adding upgrading capacities at these plants could be determined with some precision only by the owners or operators of these plants. The Task Force believes that there may be significant advantages in pursuing these options. However, the necessary steps will have to be taken by the owners or operators.

4.0 ACKNOWLEDGEMENT

The ACR Oil Sands Task Force expresses its sincere appreciation and extends thanks to Mr. T.J. McCann of RTM Engineering Ltd., Mr. G.E. Dennis of Dennis Consulting and Mr. L.D. Dowdle of ESSO Resources Canada Ltd. for their major contributions.

The Task Force also extends its thanks to the Canadian Heavy Oil Association for inviting the Task Force to their December 1987 meeting and suggesting this topic which was extremely timely.

5.0 ALBERTA CHAMBER OF RESOURCES AND OIL SANDS TASK FORCE

Formerly known as the Alberta Chamber of Mines, the Chamber is committed to fostering the orderly development and public appreciation of energy, metallic and industrial minerals.

In early 1980's the Chamber identified the Athabasca oil sands as their priority mineral resource for development in this decade. Toward this end, a Task Force of industry and government representatives was set up in 1984 to promote oil sands development.

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